DIRECT TESTIMONY OF

ANNA SOMMER

ON BEHALF OF SOUTHERN ALLIANCE FOR CLEAN ENERGY AND

SOUTH CAROLINA COASTAL CONSERVATION LEAGUE

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I. INTRODUCTION AND SUMMARY

Q: Please state your name and professional title.

A: My name is Anna Sommer. I am a Principal at Energy Futures Group. My business address is 30 Court Street, Canton, NY 13617.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of the South Carolina Coastal Conservation League ("CCL") and the Southern Alliance for Clean Energy ("SACE").

Q: Please describe Energy Futures Group.

A: Energy Futures Group (EFG) is a clean-energy consulting firm headquartered in Hinesburg, Vermont, with offices in Boston and New York. EFG designs, implements, and evaluates programs and policies to promote investments in efficiency, renewable energy, other distributed resources, and strategic electrification. EFG staff have delivered projects on behalf of energy regulators, government agencies, utilities, and advocacy organizations in forty states, eight Canadian provinces, and several countries in Europe.

EFG brings to its work a unique combination of technical, economic, program, and policy expertise. EFG staff have critically evaluated and helped develop hundreds of efficiency and renewable energy programs, many of which have subsequently won awards for excellence. Recent work involves efficiency program portfolios and policies in each of the fifteen highest-ranking states on the ACEEE State Energy Efficiency Scorecard, as well as in Ontario, Manitoba and British Columbia. We have also provided expert witness testimony on efficiency programs, integrated resource planning, and

related policy issues in regulatory proceedings in twenty states and five Canadian provinces.

Q: Please describe your education and work experience.

A: I have worked for over 15 years in electric utility regulation and related fields. During that time, I have reviewed dozens of integrated resource plans ("IRPs") and related planning exercises. I have reviewed planning modeling based on multiple models including Aurora, Capacity Expansion Model, EnCompass, PLEXOS, PowerSimm, PROSYM, PROMOD, SERVM, and System Optimizer and have had formal training on the Aurora, EnCompass, PowerSimm, and Strategist models.In my professional career I have reviewed dozens of IRPs and related planning analyses in jurisdictions all over the country and in Canada.

I hold a B.S. in Economics and Environmental Studies from Tufts University and an M.S. in Energy and Resources from University of California Berkeley. I have also taken coursework in data analytics at Clarkson University and in Civil Engineering and Applied Mechanics at McGill University and participated in the U.S. Department of Energy sponsored Research Experience in Carbon Sequestration ("RECS"). My work experience is summarized in my resume, provided as **Exhibit AS-1.**

Q: Have you previously provided expert witness testimony?

A: Yes, I have testified before utility commissions in Indiana, Michigan, Minnesota, New Mexico, North Carolina, Puerto Rico, and South Dakota.

Q: What is the purpose of your testimony in this proceeding?

A: The purpose of my testimony is to evaluate the extent to which the 2020 Integrated Resource Plan ("2020 IRP") filed by Dominion Energy South Carolina

("DESC") meets South Carolina's standards for IRPs and comports with common IRP practices in other jurisdictions. I structured my review to, as much as possible, focus on the DESC IRP itself, and give my assessment of whether the IRP as filed has the elements set forth in the Energy Freedom Act ("EFA") and more generally, whether it serves the intended purposes of integrated resource planning. I generally do not address the reasonableness of DESC's assumptions, methodologies, and outputs; that review is covered by the testimony of my colleague Dr. David Hill. Because my conclusions regarding DESC's IRP often diverge from those provided by Charles River Associates in its review of the 2020 IRP ("CRA Review"), I also assessed the CRA Review for the purposes of explaining why I arrived at different conclusions.

Q: Please summarize your key findings and recommendations.

A: My two primary findings are:

1. The DESC 2020 IRP does not include or adequately assess several elements specified in Section 58-37-40(B)(1) of the EFA.
2. The DESC 2020 IRP does not provide sufficient information to allow the Commission to adequately balance the factors in Section 58-37-40(C)(2) of the EFA.

Consequently, I conclude that the DESC 2020 IRP does not constitute "the most reasonable and prudent" plan for how DESC will meet its energy and capacity needs, as the EFA directs, and recommend that the Commission reject the DESC IRP in light of these deficiencies and require DESC to file a corrected IRP. I also recommend that the Commission consider adopting policies to improve the transparency of the IRP process moving forward; these include establishing a stakeholder process, requiring a

collaborative to help DESC choose the capacity expansion model it will use in creating its next IRP, and requiring DESC to provide no or low-cost options to intervenor who would like to perform their own IRP modeling runs. A minimum standard for transparency, regardless of whether it is the IRP modeling, the load forecasting or otherwise, would be to require utilities to provide their input and output modeling files, model manual, data sources, and assumptions upfront. In general, all of my recommendations are intended to help the Commission ascertain and determine the "most reasonable and prudent" plan.

Q: What information did you review in preparation of this testimony?

A: I primarily reviewed DESC's IRP, the CRA Review, and the IRP provisions of the EFA. While I also reviewed certain discovery responses from DESC, I tried to minimize this aspect of my review to better assess the sufficiency of the IRP as a standalone document intended to communicate DESC's long-term planning process and conclusions to South Carolina ratepayers, intervenors, and the South Carolina Public Service Commission ("Commission").

II. ANALYSIS OF DESC'S 2020 IRP UNDER THE EFA

A. Requirements of the EFA

Q: Under the EFA, what elements must a utility include in its IRP?

A: The EFA provides that a utility IRP "shall include" nine elements:

> *a) a long-term forecast of the utility's sales and peak demand under various reasonable scenarios;*
> *b) the type of generation technology proposed for a generation facility contained in the plan and the proposed capacity of the generation facility, including fuel cost sensitivities under various reasonable scenarios;*

> *c) projected energy purchased or produced by the utility from a renewable energy resource;*
> *d) a summary of the electrical transmission investments planned by the utility;*
> *e) several resource portfolios developed with the purpose of fairly evaluating the range of demand-side, supply-side, storage, and other technologies and services available to meet the utility's service obligations. Such portfolios and evaluations must include an evaluation of low, medium, and high cases for the adoption of renewable energy and cogeneration, energy efficiency, and demand response measures, including consideration of the following:*
> *i. customer energy efficiency and demand response programs;*
> *ii. facility retirement assumptions; and*
> *iii. sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks;*
> *f) data regarding the utility's current generation portfolio, including the age, licensing status, and remaining estimated life of operation for each facility in the portfolio;*
> *g) plans for meeting current and future capacity needs with the cost estimates for all proposed resource portfolios in the plan;*
> *h) an analysis of the cost and reliability impacts of all reasonable options available to meet projected energy and capacity needs; and*
> *i) a forecast of the utility's peak demand, details regarding the amount of peak demand reduction the utility expects to achieve, and the actions the utility proposes to take in order to achieve that peak demand reduction.*

S.C. Code Ann. §58-37-40(B)(1).

The EFA also provides that an IRP "may" include "distribution resource plans or integrated system operation plans." S.C. Code Ann. §58-37-40(B)(2).

Q: What does the EFA provide about the Commission's review of utility IRPs?

A: The EFA says the Commission must review an IRP to ensure it is the "most reasonable and prudent" and lists seven factors for the Commission to balance in its

discretion when reviewing whether the proposed IRP represents the most reasonable and prudent plan:

> *The commission shall approve an electrical utility's integrated resource plan if the commission determines that the proposed integrated resource plan represents the most reasonable and prudent means of meeting the electrical utility's energy and capacity needs as of the time the plan is reviewed. To determine whether the integrated resource plan is the most reasonable and prudent means of meeting energy and capacity needs, the commission, in its discretion, shall consider whether the plan appropriately balances the following factors:*
>
> *a) resource adequacy and capacity to serve anticipated peak electrical load, and applicable planning reserve margins;*
> *b) consumer affordability and least cost;*
> *c) compliance with applicable state and federal environmental regulations;*
> *d) power supply reliability;*
> *e) commodity price risks;*
> *f) diversity of generation supply; and*
> *g) other foreseeable conditions that the commission determines to be for the public interest.*

S.C. Code Ann §58-37-40(C)(2).

Q: In light of these elements of the EFA, what should the Commission consider when evaluating IRPs?

A: The Commission should consider the nine elements listed under S.C. Code Ann. §58-37-40(B)(1). Further, it should consider the seven factors listed in S.C. Code Ann §58-37-40(C)(2) in determining whether, on balance, the proposed IRP represents the most reasonable and prudent means of meeting the electrical utility's energy and capacity needs. For that to occur, the filing utility needs to supply sufficient information with regard to each factor to enable the Commission to make its determination. Additionally, the Commission in evaluating the "reasonableness" and "prudence" of a utility's IRP

should consider whether the utility developing the IRP followed industry norms, standards, and practices and used assumptions common throughout the industry; where a utility departs from these standards, it should thoroughly document and explain where and why that is the case. The use of these industry norms and standards is necessary for an IRP to satisfy its underlying purpose as a document that enables the provision of just and reasonable service to ratepayers.

Q: How would you define an IRP?

A: In the words of Lawrence Berkeley National Laboratory ("LBNL"), "[r]esource planning processes provide a forum for regulators, electric utilities, and electricity industry stakeholders to evaluate the economic, environmental, and social benefits and costs of different investment options. By facilitating a discussion on future goals, challenges and strategies, resource planning processes often play an important role in shaping utility business decisions."[1] Effective and meaningful IRPs do not merely serve as checklists for a set of analyses; rather, they reflect thorough and thoughtful stakeholder engagement, set forth the utility's perspective and analytical processes, clearly communicate the analyses that combine to make the IRP, and give a clear decision making path for the utility. In addition, well-done IRPs often discuss the ways in which the utility's next IRP might change in the future, such as how assumptions may change or further analyses the utility might conduct in preparation for its next IRP.

IRPs are complex, but they should not be opaque. There are many steps a utility can take to make its IRP more accessible, more readable, more digestible, and more transparent for stakeholders and regulators. I discuss several of those steps in this

[1] Karhl, Fritz, et al., *The Future of Electricity Resource Planning*, Lawrence Berkeley National Laboratory (September 2016), available at https://emp.lbl.gov/sites/all/files/lbnl-1006269.pdf.

testimony and offer examples of how other utilities have approached the issues and topics I describe. These examples are not intended to demonstrate perfection, but rather are intended to contrast what is presented in DESC's IRP with what I typically see in IRPs from comparable utilities.

B. Required Elements of an IRP Under the EFA

Q: Does the DESC 2020 IRP contain the nine required elements as provided under the EFA?

A: In part, yes, but in several key respects, the IRP appears to fall short. The following two tables compare DESC's representation of its EFA compliance with my assessment of whether the 2020 IRP includes the specified elements. Below I have reproduced DESC's table in its IRP describing its EFA compliance, [2] along with my own assessment of DESC's compliance with these requirements below.

[2] DESC 2020 IRP at 7.

Table 1. Assessment of DESC's Satisfaction of Act 62 Requirements

Act 62 58-37-40	Requirement	Does the IRP Section Referenced by DESC Satisfy this Element?
(B)(1)(a)	a long-term forecast of the utility's sales and peak demand under various reasonable scenarios;	Sections I.A and I.B of the DESC IRP lack sufficient information to judge the reasonableness of the scenarios, don't explicitly provide the high and low scenario values, and seemingly do not even use them.
(B)(1)(b)	the type of generation technology proposed for a generation facility contained in the plan and the proposed capacity of the generation facility, including fuel cost sensitivities under various reasonable scenarios;	Section II.B.5.c provides the technology types, but the only fuel cost sensitivities given are for gas and do not appear to be internally consistent with the CO_2 prices used.
(B)(1)(c)	projected energy purchased or produced by the utility from a renewable energy resource;	Section II.B.3.c does not specify the source it comes from. Further, it only shows RE from one portfolio. In Section II.B.5.c, it gives a table of RE by decade, but this should be annual to be digestible and it lacks the type and source of energy.
(B)(1)(d)	a summary of the electrical transmission investments planned by the utility;	Section III includes a table with planned transmission projects and the tentative completion date for each project. The section does not describe the purpose of any of the studies mentioned nor how any of these investments may affect the various portfolios evaluated by DESC.

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(B)(1)(e)	several resource portfolios developed with the purpose of fairly evaluating the range of demand-side, supply-side, storage, and other technologies and services available to meet the utility's service obligations. Such portfolios and evaluations must include an evaluation of low, medium, and high cases for the adoption of renewable energy and cogeneration, energy efficiency, and demand response measures, including consideration of the following: (i) customer energy efficiency and demand response programs; (ii) facility retirement assumptions; and (iii) sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks;	Section II.B.5.c provides a table of the potential resources considered and a description of the resource plans. But DESC did not appear to evaluate low, medium, and high renewable cases. The IRP is not clear as to whether DESC adjusted supply-side capacity in plans based on the level of DSM assumed. And the Company does not appear to have evaluated low, medium, and high cases of cogeneration (Section II.B.3.d). Finally, it is unclear how DR was treated.
(B)(1)(f)	data regarding the utility's current generation portfolio, including the age, licensing status, and remaining estimated life of operation for each facility in the portfolio;	Section II.B.1 discusses the licensing status, age, and end-of-life date of DESC's hydro and nuclear resources. Section II.B.3 discusses "Future Clean Energy" so it's not clear how this relates. Section II.B.4.shows the online date, probable retirement date, and size and type of existing units. But without explanation, DESC doesn't seem to adopt all these dates in its modeling.
(B)(1)(g)	plans for meeting current and future capacity needs with the cost estimates for all proposed resource portfolios in the plan;	Section II.B.5.c provides net present values ("NPVs"), though I think there is a more useful way to do this that I discuss later in testimony. And only two explicit plans are given – the tables provided for RP2 and RP8 on pages 51 and 52 of the IRP.
(B)(1)(h)	an analysis of the cost and reliability impacts of all reasonable options available to meet projected energy and capacity needs; and	Section II.B.5.c provides no rate, bill, or reliability impacts, and only provides tables with data on the calculation of effective reserve margin for RP2 and RP8.

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(B)(1)(i)	a forecast of the utility's peak demand, details regarding the amount of peak demand reduction the utility expects to achieve, and the actions the utility proposes to take in order to achieve that peak demand reduction.	Section I.A does contain a forecast of peak demand, but Sections II.A.1 and II.A.2 provide only a single point estimate of DR reduction and no projection of EE related investment. Further, because of the requirement to provide low, medium, and high levels of DSM it would be reasonable to interpret this requirement as providing that projection for all scenarios as well as a description of how the assumptions underlying those scenarios change.
(B)(2)	An integrated resource plan may include distribution resource plans or integrated system operation plans.	Section II.A.2 provides nothing approximating a distribution resource plan ("DRP") or integrated system operation plan ("ISOP"). And Section II.B.2 is a mere two paragraphs describing the Company's AMI and distribution automation activities. This does not reasonably constitute a DRP or ISOP either.

Q: It seems that you disagree with DESC about whether the 2020 IRP includes (or adequately assesses) several of the elements outlined in the EFA. Of the elements you believe DESC did not adequately address, are there any you would like to highlight as particularly important?

A: Yes. I would like to highlight subsection (B)(1)(e), which, in my opinion, is the "heart" of the IRP analysis specified by the EFA and deserves particular attention. That subsection, again, requires:

> *several resource portfolios developed with the purpose of fairly evaluating the range of demand-side, supply-side, storage, and other technologies and services available to meet the utility's service obligations. Such portfolios and evaluations must include an evaluation of low, medium, and high cases for the adoption of renewable energy and*

> *cogeneration, energy efficiency, and demand response measures, including consideration of the following: (i) customer energy efficiency and demand response programs; (ii) facility retirement assumptions; and (iii) sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks . . .*

First, this section calls for a fair evaluation of a broad range of demand-side, supply-side, storage, and other resources, and explicitly directs high, medium, and low renewable energy ("RE"), cogeneration ("cogen"), energy efficiency ("EE"), and demand response ("DR") cases. However, it is unclear from the IRP how or if DESC evaluated low, medium, and high RE, cogen, and DR scenarios.

Second, the statute specifically lists consideration of "facility retirement assumptions" as part of the analysis. The utility should evaluate the range of demand-side, supply-side, storage, and other resources as near-term replacement resources for existing generators. It also appears from the text of the IRP that despite the table of existing units given on page 33, DESC did not always adopt a unit's planned retirement date. For example, McMeekin and Urquhart have planned 2028 retirement dates and yet Resource Plan 4 ("RP4") seems to be the only plan that retired those units in that year. A list of planned unit retirement dates serves no purpose in the IRP if not used as a reference case retirement assumption.

Third, I do not believe that a utility of DESC's size can accurately conduct the detailed portfolio analysis using multiple scenarios and sensitivities described in subsection (B)(1)(e) without a capacity expansion model that has the capability to select resources and optimize for a particular outcome. Rather than using a capacity expansion model, however, DESC used an Excel spreadsheet to develop its capacity expansion plans, along with the PROSYM model to analyze production costs.

Q: Why is a capacity expansion model important, and why do you take issue with DESC's use of PROSYM?

A: DESC's use of the PROSYM production cost model rather than a capacity expansion model does not comport with standard industry practice for a utility of its size. Where resource choices are not limited to one or two types by applicable energy policy, using a capacity expansion model is standard industry practice. A capacity expansion model simulates not just the dispatch of generators as PROSYM does, but also has the capability to select and retire units based on economics. Because of the complexity of capacity expansion optimization, it is not possible to infer the best combination of resource additions, the most economic retirement dates, and the ways in which those resource choices might change using just a production cost model like PROSYM.

Q: Do you mean to suggest that *any* model with both production cost and capacity expansion capabilities would be a superior choice?

A: No. There are many considerations that affect what IRP model a utility chooses; it would be important to understand which model DESC may select and how DESC would use the model before endorsing its use for IRP purposes. For instance, the majority of IRP models have to simplify the representation of time while simultaneously performing capacity expansion. They do this either by using load duration curves which order hours from highest load to lowest load[3] or by using some sort of simplified chronology such as sampling a subset of hours and/or grouping hours into multi-hour blocks to reduce the number of time slices represented in the model. These simplifications are common and

[3] If a planning period consisted of merely three hours with load of 800 MW in Hour 1; 1,000 MW in Hour 2; and 900 MW in Hour 3, a load duration curve would reorder the hours as follows: Hour 2, Hour 3, Hour 1.

necessary, but load duration curves are generally inferior to chronological representation because they cannot model the sequencing of time-dependent resources like battery storage or demand response. This can bias the model against the selection of those resources and paint an unrealistic picture of the system under conditions of heavy buildout of time-dependent resources.

Model transparency is another important issue. For example, in prior cases I have worked on involving the PLEXOS model,[4] I have been unable to view the input files, model settings, or model manual without a read-only license. That read-only license costs $5,000, and if paid by the intervenor, would mean that a cost is being imposed to obtain discoverable information. It is my understanding that PLEXOS may have been updated to allow inputs and model settings to be exported, but the manual is still not available without a license.

In any event, though, I do not believe that DESC's use of PROSYM for its 2020 IRP comports with standard industry practice and may render its analysis deficient under subsection (B)(1)(E) of the EFA. I would recommend to the Commission that it consider directing DESC to engage stakeholders in a collaborative process to choose a capacity expansion model to use in its next IRP. I recently participated in a collaborative to select a capacity expansion model for DTE Energy in Michigan, and found that collaborative to be well run and informative. I particularly appreciated the list of evaluation criteria developed for how DTE energy would select an IRP model; those criteria are attached to my testimony as **Exhibit AS-2**.

[4] In a discovery response, DESC indicated that it intends to use PLEXOS in its 2021 IRP assuming implementation of that model is successful. DESC Response to SACE CCL DR 2-43.

Q: Is there anything else you would like to note about the DESC 2020 IRP and whether it included the elements outlined in the EFA?

A: Yes. An Integrated Resource Plan should be just that—a plan for how the utility will proceed. In my opinion, the DESC 2020 IRP is generally missing a clear plan of action. **Exhibit AS-3** gives an example of an action plan from Vectren's 2019/2020 IRP. The Vectren action plan first places the IRP in the context of recent regulatory activity affecting its generation mix. It then discusses environmental compliance activities affecting current generating units. Finally, it talks about the steps it will take over the next three years to implement the preferred portfolio, gives a schedule of those steps, and a brief mention of its intention to incorporate feedback internally and externally to improve its next IRP filing. DESC's 2020 IRP lacks all these elements. For example, the 2020 IRP states that DESC "recommends following a short-term plan consistent with [Resource Portfolio 2 ("RP2")]" and that DESC "shall continue to study and reasonably develop the alternatives put forth in RP8." Under both RP2 and RP8, DESC apparently intends to acquire 51 MW of solar capacity in 2021, but DESC provides no description of how it will do so. Furthermore, DESC says that is will explore near-term retirement of older combustion turbines but gives absolutely no indication of what that analysis will entail and when it will be completed. It is my expert opinion that identification of a preferred resource plan and accompanying plan of action is crucial to the Commission's ability to weigh factors specified in the EFA, which I discuss in the following section.

C. Commission Balancing Factors

Q: Please explain the significance of the seven factors specified in Section 58-37-40(C)(2) of the EFA?

A: I will take each element one by one. Regarding the first, "resource adequacy and capacity to serve anticipated peak electrical load" implicate the need for a load forecast, reserve margin (or other resource adequacy requirement), and an assessment of accredited capacity by resource. The load forecast—the utility's projection of its customers' energy and capacity demands over the planning horizon—is one of the single most important inputs in an IRP, because it defines the need that the utility's plan must meet. And because the reserve margin requirement serves as the utility's "cushion" of excess capacity in case of extreme weather, unit outages or other unforeseen events, it is also very important. I would strongly recommend to the Commission that it reject an IRP based on resource adequacy standards that are not industry standard and are not based on a reserve margin analysis that has not been thoroughly vetted by the Commission and by intervenors.

As to the 2020 IRP, I cannot recall ever reviewing an IRP that used a "base" or "peaking" reserve margin. Those are not standard industry requirements for resource adequacy, and the DESC 2020 IRP provides no basis to evaluate the necessity of those requirements or the manner in which they were developed.

Q: What kind of information should the Commission keep in mind when evaluating "customer affordability and least cost"?

A: A calculation of net present value ("NPV") is clearly important and required by the EFA for each portfolio under all scenarios and sensitivities evaluated. DESC never explicitly provides its planning period in the 2020 IRP, though the CRA Review suggests the planning period goes out until at least 2049. A typical modeled planning period is 20 years, sometimes as long as 30 years. So giving a 20 or 30-year NPV would be valuable.

The CRA Review also suggests there is an end-effects period, i.e. a period over which the costs in the last modeled year are extrapolated. If so, the NPV calculation should be evaluated with and without the end-effect costs. This is because the further you go out into the future the more uncertain your costs are and it's important to know if the relative ranking of portfolios is driven by planning period costs or end-effects costs.

Because the EFA explicitly specifies assessment of customer affordability, I would also encourage the Commission to require that DESC calculate the rate and bill impacts of the various portfolios in the IRP, not just a levelized NPV of revenue requirements. **Exhibit AS-4** presents an example of how one utility, Xcel Energy, the largest utility in Minnesota, determines the rate impacts of its preferred plan. A useful addition to this would be to also calculate average bills for at least residential customers since underlying consumption is likely to change over the planning period. Presenting portfolio costs in terms of revenue requirements as well as rate and bill impacts will help the Commission evaluate when average rate increases are likely to occur and whether those rate increases necessarily imply bill increases, because they do not always.

Q: What kind of information should the Commission use to evaluate "compliance with applicable state and federal environmental regulations"?

A: IRPs often include evaluations of unit compliance with state environmental regulations, along with the Coal Combustion Residuals rule, the Steam Electric Power Generating Effluent Guidelines and Standards, National Ambient Air Quality Standards, etc., and current and potential future greenhouse gas-related rules. **Exhibit AS-5** is an example of this kind of documentation from Xcel Energy. DESC's cursory discussion of environmental rules in the 2020 IRP does not include any meaningful analysis or

consideration of how state or federal environmental regulations might affect DESC's generating units and therefore resource choices.

Q: What kind of information should the Commission use to evaluate "power supply reliability"?

A: Power supply reliability data can help the Commission understand whether there is an existing reliability issue that merits further evaluation in the IRP, or whether DESC's system is particularly at risk due to disruptive events such as hurricanes. I would recommend that DESC be required to include several years of recent generator performance data such as capacity factor and net generation as well as data reported to the North American Electric Reliability Corporation, such as generating unit equivalent availability factor, forced outage rate, and other metrics. It would also be useful to develop a requirement for reporting of individual events like hurricane-related outages; this could include information such as the location of outages, length of outages, or repairs needed to bring customers back online. DESC's 2020 IRP does not include this information.

Q: What kind of information should the Commission use to evaluate "commodity price risks"?

A: The manner in which commodity price risks are assessed depends in part on the model choice. Some utilities perform probabilistic analyses of fuel and purchased power prices using historic data to characterize the volatility of those variables. This may be an option for DESC.[5] Others use sensitivity analysis. Fuel prices, especially gas prices, vary seasonally and should be modeled as such. It is not clear from the 2020 IRP

[5] Note that it is not appropriate to apply probabilistic analysis to new resource capital costs nor would I interpret the EFA as requiring such.

whether DESC did this. And all commodity forecasts should be internally consistent, i.e., the gas price, carbon price, and wholesale power price are all based on the same scenario assumptions. It does not appear to me that DESC's commodity pricing is indeed internally consistent.

Q: What kind of information should the Commission use to evaluate "diversity of generation supply"?

A: The diversity of generation supply can be depicted by presenting a chart showing the proportion of technology types utilized on an energy and capacity basis. DESC presents a chart of this type on page 32 of its IRP, but for its current portfolio only. However, I would caution the Commission against using such charts as the exclusive factor upon which to judge whether diversity has been achieved. Diversity can also be measured in terms of number of discrete units utilized by the system, the size of the system's single largest generator contingency, the presence of fuel price risk or lack thereof, and other metrics. Said another way, it is important to understand the impacts of generation source diversity—or lack of it—on reliability, rate volatility, and regulatory risk, and diversity should not merely be judged based on the quantity of energy or capacity from a single source.

III. CRA REVIEW OF DESC'S 2020 IRP

Q: The authors of the CRA review of DESC's IRP generally found the IRP to be reasonable. Do you have a reaction to that?

A: Yes. I disagree with CRA's conclusion about the reasonableness of DESC's IRP. In conducting its review, CRA appears to have held DESC to an unreasonably low bar. The CRA Review provides that "[i]n general, CRA judged an

assumption or approach to be reasonable when it was supported by recent third-party studies, publicly available market data, planning documents from nearby utilities, or CRA's own industry experience."[6] I am familiar with CRA's "industry experience" to some degree through my participation, on a behalf of a client, in NIPSCO's 2018 IRP Update;[7] CRA led the process for that Update and in nearly every aspect, the NIPSCO 2018 IRP Update is a notably more thorough and better documented than the DESC 2020 IRP.

For example, CRA states that "For gas turbine technologies, CRA has observed industry costs as low as $476/kW for simple cycle turbines and as high as $1,300/kW for more advanced aeroderivative technologies."[8] This response is indifferent to the quality of the source and gives no recommendation about how one might reconcile this incredibly wide range of costs into a useable input assumption. In contrast, the NIPSCO 2018 IRP Update used the following sources of capital costs to develop initial assumptions:[9]

[6] CRA Review at 12.
[7] NIPSCO 2018 IRP Update, available at https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/2018-nipsco-irp.pdf?sfvrsn=15.
[8] CRA Review at 61.
[9] NIPSCO 2018 IRP Update, *supra* note 7, at 51.

Table 2. Reproduction of NIPSCO Figure 4-5 Data Sources for Third Party Resource Review

Data Source	Description
Sargent & Lundy	NIPSCO Integrated Resource Plan Engineering Study Technical Assessment (2015)
Energy Information Administration (EIA)	Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants (2018 Annual Energy Outlook)
Utility Integrated Resource Plans	Empire District Electric Company, Puget Sound Energy, Avista Utilities and Idaho Power (screened for filings with transparent data within the last 6 months to year)
Lazard	Levelized Cost of Energy Analysis Version 11.0 (2017)
	Lazard Levelized Cost of Storage Version 3.0 (2017)
IHSMarkit	US Solar PV Capital Cost and Required Price Outlook
	US Wind Capital Cost and Required Price Outlook
	US Battery Storage: Costs, Drivers, and Market Outlook (2017)
	North American Power Market Fundamentals: Rivalry, October 2017 – New Capacity Characteristics & Costs
Bloomberg New Energy Finance	Historical and forecast U.S. PV Capex Stack by Segment and Region
	Key cost input in LCOE Scenarios, 1H 2017
	Benchmark Capital Costs for a Fully-Installed Energy Storage System (2017)
National Renewable Energy Technology Laboratory (NREL)	Annual Technology Baseline 2017

Following this third-party source review, NIPSCO concluded: "Given relatively large uncertainty ranges for certain technologies and given even larger uncertainty regarding future cost trends, NIPSCO determined that it was necessary to conduct an RFP process to collapse the uncertainty and identify transactable projects that could be available for future capacity needs."[10]

The CRA Review did not use this industry experience to recommend that DESC query other sources, more heavily weigh IRP assumptions based on "transactable" data, or make any such comparisons itself. And the CRA Review did not even mention that DESC may want to issue an all-source RFP. It simply concludes that because the

[10] *Id*. at 53.

selected value falls into an identified range, irrespective of quality of source, it must reasonable.

Q: In what other ways do you disagree with the conclusion of the CRA Review?

A: The CRA Review did not sufficiently evaluate the ability of the DESC IRP itself to communicate key inputs and results; in several instances, it appears that CRA had to collect significant additional information in order to assess the IRP, some of which, like interviews of DESC IRP personnel, would not be available to stakeholders or to the Commission. For example, with regards to the load forecast, CRA says that it did the following:

> CRA conducted interviews and reviewed testimony of DESC load forecasting experts and was provided data in native format (e.g., Excel) containing historical sales data by customer class, seasonal peak data by customer class, peak seasonal load calculations, DSM amounts, and load forecasts used in the portfolio modeling of the 2020 IRP. CRA also reviewed statistical outputs from the SAS models used to perform the regression analysis and macroeconomic forecast that drives customer sales and growth in the 2020 IRP.[11]

Indeed, the CRA Review was frequently more descriptive of and, therefore informative about, DESC's methodology and assumptions than was the actual IRP; this also seemed to have no bearing on CRA's evaluation. For example, CRA states, "DESC's loss of load expectation ("LOLE") study was based on an industry-standard metric of 0.1 days per year or 1 day in ten years, and the application of both supply-side risk and demand-side load shapes in the study were reasonable. In future LOLE study reviews, DESC may consider evaluating hourly granularity and including weather risk to further test the robustness of its reserve margin policy." The DESC IRP itself does not

[11] CRA Review at 8-9.

indicate that DESC's LOLE study is not an hourly study or that it does not account for weather risk; these facts should have raised concerns about the basis for DESC's reserve margin requirements, rather than merely resulting in CRA's suggestion that DESC conduct more analysis in the future.

The shortcomings of the CRA Review underscore the need for critical, thorough documentation and transparency in any third-party review of an IRP. Much of this information should be documented in the IRP itself and that which cannot be, e.g. Excel spreadsheets, should be accessible to stakeholders who have signed the requisite non-disclosure agreement.

Finally, CRA did not evaluate whether the IRP complied with the requirements of the EFA; whether the DESC IRP complies with applicable statutes should certainly be a factor in determining the reasonableness of the IRP.

IV. OTHER CONSIDERATIONS IN EVALUATING THE DESC 2020 IRP

Q: Do you have any other recommendations for what should be included in the DESC IRP?

A: Yes. I would like to address several items the Commission could require DESC to include in its IRP or as part of its IRP process that would improve the transparency of the IRP process or improve the quality of the IRP as a standalone document.

Q: What are your recommendations with regard to transparency?

A: As mentioned previously, transparency is an important element in an IRP. There are some common ways that utilities make IRPs more accessible, more readable, and more digestible. One such step is for a utility to provide, as part of the IRP submission,

as much documentation of the IRP as possible. Sometimes, utilities are obligated to provide specific information. For example, Indiana IRP rules require at the time of IRP submission:

> A technical appendix containing supporting documentation sufficient to allow an interested party to evaluate the data and assumptions in the IRP. The technical appendix shall include at least the following: (A) The utility's energy and demand forecasts and input data used to develop the forecasts. (B) The characteristics and costs per unit of resources examined in the IRP. (C) Input and output files from capacity planning models, in electronic format. (D) For each portfolio, the electronic files for the calculation of the revenue requirement if not provided as an output file.[12]

Even where such rules are not in place, however, utilities can provide modeling documentation on an informal basis; for example, by contacting the intervening parties to ask if they will want access to the modeling files in their executable format or in a common format, if applicable, and providing those under separate cover at the same time that the IRP is submitted.

Q: Has DESC taken any of these steps with its 2020 IRP?

A: No. DESC has not provided its IRP documentation up front. DESC can and should choose to be transparent about its modeling. Improved transparency would not only assist the parties in better understanding DESC's assumptions and methodology, it would result in a better product and allow stakeholders and the Commission to have greater confidence in DESC's plan.

Q: Are there other steps utilities can take to make their IRPs more transparent?

A: Yes. Utilities can write their IRPs so as to provide insight into their methodologies and processes, not merely to provide the bare minimum of information.

[12] 170 Indiana Admin, Code §4-7-2 (Integrated resource plan submission).

For example, the Northern Indiana Public Service Company ("NIPSCO"), in its 2018 IRP Update, provided the sources of data used in developing the load forecast, briefly described each sector model developed for the forecast, described the key explanatory variables it used, and frequently provided model equations or statistics.[13] Some, but not all of this information is provided in the Testimony of Joseph Lynch, but as I described previously, this does not substitute for having that content in the IRP.

Q: Does the DESC IRP provide sufficient insight into its methodologies and processes?

A: No. In many places, the 2020 IRP is more "informational" in nature, and somewhat arbitrary in terms of where detail is provided and where it is lacking. For example, DESC provides more detail on its rationale for choosing its "low case" rate of load growth than it does on its methodology for developing its "base case" load forecast. The base load forecast is merely presented and no information about DESC's methodology or data sources is given. To give another example, in discussing (non-trivial sales) to wholesale customers, DESC simply says, "[t]he Company plans to successfully renew these contracts with current customers and has included the load in its forecast."[14] DESC says nothing about when those contract renewals will happen or whether customers might switch from requirements to partial or whole non-requirements customers.[15] The successful renewal of those contracts is not merely DESC's decision, and therefore anyone reading the IRP would not be able to judge whether including this load is well reasoned and justified.

[13] See NIPSCO 2018 IRP Update, *supra* note 7, at 31. The development of NIPSCO's IRP Update was led by Pat Augustine of CRA, who also participated in the CRA Review of the DESC 2020 IRP.
[14] DESC 2020 IRP at 11-12.
[15] It is not appropriate for a utility to plan to meet non-requirements load. It has no obligation to serve that load and therefore should not be incorporated into an IRP.

In addition, the DESC IRP lacks an assessment comparing only the resources currently on a utility's system with the utility's projected load. While such a comparison does not appear to be explicitly required by the EFA, such a comparison is useful because it highlights when a resource gap will first occur and the magnitude of that gap. The tables DESC includes on pages 51 and 52 of the IRP do not explicitly do this, so the 2020 IRP contains no such table or chart.

Q: When intervenors can obtain documents and data through the discovery process, why should it matter whether the utility describes its rationale, thought processes, and methodologies in the IRP?

A: An IRP should be understandable as a stand-alone document to the extent possible because it underlies the fundamental function of a utility – to provide just and reasonable service to ratepayers. An IRP should demonstrate that the utility has performed its due diligence in achieving that standard. A thoroughly explained and well-documented IRP demonstrates that the utility considered risks and uncertainties both common and unique to its jurisdiction, shows that its reasoning was well developed and justified, and communicates that information to ratepayers and regulators. DESC's 2020 IRP, by and large, does not do this.

In some instances, such as with respect to the load forecast, additional information is provided in DESC's testimony, but this does not rectify the deficiencies in the IRP. The value of an IRP extends beyond the docket in which it is filed so any person who was not a party to the IRP proceeding may be unaware of the existence of accompanying testimony. Furthermore, South Carolina statute directs the Commission to decide

whether to approve, reject, or modify an IRP not whether to approve, reject, or modify an IRP and its accompany testimony.

Q: What suggestions do you have regarding transparency in the IRP process itself?

A: I recommend that the Commission consider requiring DESC to conduct an IRP stakeholder process moving forward. A common practice is to conduct a stakeholder process prior to the filing of the IRP. These stakeholder processes are often intended to help the parties understand each other's viewpoints, provide feedback on the assumptions made by the utility, and ideally narrow the number of contested issues in the IRP case.

Q. What are some common characteristics of stakeholder processes?

A: In my experience IRP stakeholder workshops function best when the utility takes seriously the feedback stakeholders offers it and makes a good faith attempt to model the resources, portfolios, and scenarios that stakeholders request. It's hard to be prescriptive about these qualities, but they are important not just for the robustness of the IRP but for the perceived seriousness and comprehensiveness of any IRP. Some other, more easily defined best practices include:

1. Use of a credible third-party moderator (i.e., typically not the utility nor its IRP consultant) to facilitate questions and answers and keep all parties on schedule. The moderator can also be responsible for making sure that parties on the phone can hear everyone in the room where the presentation is happening and vice versa.
2. Sharing of power point presentations and data well in advance of meetings.

3. Allowing interested stakeholders the opportunity to make their own presentations on topics relevant to the IRP.
4. A schedule of meeting topics, dates, and times shared well in advance of the meetings.
5. The opportunity and time for stakeholders both in the room and in person to ask questions at each meeting.
6. The ability of any party, regardless of their status in the IRP docket, to participate in the meetings.

Q. What would you recommend to the Commission?

A: I would recommend that the Commission consider directing DESC to implement a stakeholder process that comports with the broad characteristics I've described.

V. SUMMARY AND RECOMMENDATIONS

Q: Please summarize your testimony and recommendations to the Commission.

A: In conclusion, the DESC IRP does not constitute a reasonable plan because it does not include or provide an adequate assessment of several elements specified in Section 58-37-40(B)(1) of the EFA. Indeed, some of DESC's methodologies fall short of industry standards, most particularly as it relates to its choice to use PROSYM rather than a capacity expansion model. In light of these shortcomings, the DESC cannot be considered prudent. In addition, the DESC IRP does not provide sufficient information to allow the Commission to adequately balance the factors in Section 58-37-40(C)(2) of the EFA.

Consequently, I conclude that the DESC 2020 IRP does not constitute a reasonable and prudent plan for how DESC will meet its energy and capacity needs, and recommend that the Commission reject the DESC IRP in light of these deficiencies and require DESC to file a corrected IRP. I also recommend that the Commission consider adopting policies to improve the transparency of the IRP process moving forward; these include establishing a stakeholder process, requiring a collaborative to help DESC choose the capacity expansion model it will use in creating its next IRP, and requiring DESC to provide no or low-cost options to intervenor who would like to perform their own IRP modeling runs. A minimum standard for transparency, regardless of whether it is the IRP modeling, the load forecasting or otherwise, would be to require utilities to provide their input and output modeling files, model manual, data sources, and assumptions upfront.

Q: Does this conclude your testimony?

A: Yes, it does.

STATE OF SOUTH CAROLINA
BEFORE THE PUBLIC SERVICE COMMISSION
DOCKET NO. 2019-226-E

In the Matter of: South Carolina Energy Freedom Act (House Bill 3659) Proceeding Related to S.C. Code Ann. Section 58-37-40 and Integrated Resource Plans for Dominion Energy South Carolina, Incorporated	)	CERTIFICATE OF SERVICE

I certify that the following persons have been served with one (1) copy of the Direct Testimony of Anna Sommer by electronic mail and/or U.S. First Class Mail at the addresses set forth below:

Andrew M. Bateman
Office of Regulatory Staff
1401 Main Street, Suite 900
Columbia, SC 29201
Email: abateman@ors.sc.gov

Belton T. Zeigler
Womble Bond Dickinson (US) LLP
1221 Main Street, Suite 1600
Columbia, SC 29201
Email: belton.zeigler@wbd-us.com

Carri Grube Lybarker
SC Department of Consumer Affairs
Email: clybarker@scconsumer.gov

Courtney E. Walsh
Nelson Mullins Riley & Scarborough LLP
Post Office Box 11070
Columbia, SC 29211-1070
Email: court.walsh@nelsonmullins.com

James Goldin
Nelson Mullins Riley & Scarborough LLP
1320 Main Street 17th Floor
Columbia, SC 29210
Email: jamey.goldin@nelsonmullins.com

Jeffrey M. Nelson
Office of Regulatory Staff
1401 Main Street, Suite 900
Columbia, SC 29201
Email: jnelson@ors.sc.gov

K. Chad Burgess
Dominion Energy South Carolina, Inc.
220 Operation Way - MC C222
Cayce, SC 29033-3701
Email:
Kenneth.burgess@dominionenergy.com

Matthew W. Gissendanner
Dominion Energy South Carolina, Inc.
220 Operation Way - MC C222
Cayce, SC 29033-3701
Email:
matthew.gissendanner@dominionenergy.com

Nanette S. Edwards
Office of Regulatory Staff
1401 Main Street, Suite 900
Columbia, SC 29201
Email: nedwards@ors.sc.gov

Robert Guild
Robert Guild - Attorney at Law
314 Pall Mall Street
Columbia, SC 29201
Email: bguild@mindspring.com

Richard L. Whitt
Whitt Law Firm, LLC
Post Office Box 362
401 Western Lane, Suite E
Irmo, SC 29063
Email: richard@rlwhitt.law

Weston Adams III
Nelson Mullins Riley & Scarborough, LLP
Post Office Box 11070
Columbia, SC 29211
Email: weston.adams@nelsonmullins.com

July 10, 2020

/s/ Emily E. Selden